D.T.E. 03-121
Attachment NEDGC-4-9 (a)

DIRECT TESTIMONY OF RICHARD LA CAPRA

DIRECT TESTIMONY

OF

RICHARD LA CAPRA

Q1. Please state your name, business address, and occupation.

A. My name is Richard La Capra. My business offices are located at the Bulfinch Building, 64 Broad St., Boston, Massachusetts, 02109, and I am a Utility Analyst and Principal of La Capra Associates.

Q2. Would you please state your background and experience?

A. I have been involved in project management for public utilities for over 20 years. In various professional capacities, I have worked in both research and application of utility cost analysis, pricing, load research and system planning. A more detailed description of my background is included as Attachment 1 to this testimony.

Q3. Have you previously testified on rate matters before any regulatory agency?

A. I have testified before the Massachusetts Department of Public Utilities on behalf of Boston Edison Company in the rate structure investigations (DPU 18810 and 19845) and in previous rate proceedings (DPU 1350, 1720, 85-271 and 89-100). I also have sponsored rate testimony and exhibits in various state and federal rate proceedings.

Q4. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the allocation of the total cost of service determined by Mr. Alpert among the Company's service classes.

Q5. How is your testimony organized?

A. There are three parts to the presentation of the allocated revenue requirement. The first part is a description of the embedded cost of service study used in the determination of the service class revenue requirements. The second part is a description of how functional costs are allocated to the service classes along with an explanation of the MBTA power supply allocation. The third part is a description of the Company's load research program and how its results underlie the embedded cost of service study.

Q6. Turning to the first area of your testimony, would you please summarize the results of the allocated cost of service study?

A. The results of the cost of service study indicate an overall retail revenue deficiency of 7.1% of normalized test year revenues. The allocation of the deficiency of individual retail classes resulting from the allocated cost of service are:

Service Class	Return During Test Year (%)	Test Year Deficiency at Claimed Return ($000)
Residential	7.23%	$39,487
General Service	8.87%	$46,187
115kV (MBTA)	12.42%	$ -385
115kV (MWRA)	22.93%	$ -397
Street Lighting	8.90%	$ 1,743
Total Retail Service	**8.40%**	**$86,635**

Q7. Would you please describe the approach the Company has used in allocating its embedded costs to each service class?

A. The Company has developed a time differentiated embedded cost study for determining the revenue requirement for each service class. This approach is the same as in previous Company filings except that it incorporates subsequent Department directives.

The Company's embedded cost study consists of five discrete steps:

1) Functionalization - the process of organizing plant and expense costs by functional use. The basic functions used in the study are:

a) Production

b) Power Supply Transmission

c) Local Transmission

d) High Tension Distribution, and

e) Secondary Distribution

2) Classification - the process of segregating the functionalized cost by the primary reason for its

incurrence, i.e., demand (capacity requirements), energy (continuous power requirements), or customer (connection and billing).

3) Time Differentiation - the process of determining the functionalized and classified costs attributable to differing times of the year or hours of the day.

4) Allocation - the process of apportioning the functionalized time-differentiated and classified costs to each service class based on their pro rata use of energy or demand within each time period.

5) Deficiency Determination - the process of summing the allocated costs across all time periods, classifications and functions by service class to form each class's revenue requirement and comparing it to the total revenues from the subject class. The deficiency is computed as revenue requirement less revenues adjusted for transfer of fuel costs to base rates. A positive deficiency indicates a need to increase revenues; a negative deficiency indicates a need to decrease revenues.

Q8. Would you please define the service classes used in the allocated cost study?

A. The service classes are defined primarily by general usage pattern. Specifically there are five distinct service classes i.e., Residential, General Service, Transmission-Water Authority (MWRA), Transmission-Traction (MBTA) and Lighting Loads. Each service class may be divided into rate schedules as justified by marginal cost variations, but are generally one of the five described load shapes.

Q9. How is this different from previous filings by the Company?

A. The material difference is the Company's decision to base individual rate schedules primarily on marginal costs. Essentially, the Company has derived each rate schedule on marginal costs, and as described in Exhibit BE-RDS-1 by Mr. Saunders, compared the total marginal revenues to the total Company revenue requirement. The reconciliation of the marginal revenue to the revenue requirement can then be performed on a rate schedule, service class or total Company basis. The Company has determined that the reconciliation of the marginal revenue to the revenue requirement is best performed at the level of service class. Therefore, the cost of service study develops embedded revenue requirements by service class.

Q10. Please explain the basis for selecting the service classes.

A. The service class is simply each discrete usage type, i.e., Residential, General Service, Transmission-Water Authority, Transmission-Traction, and Lighting. Each of these classes is a distinct type of service. Residential service is identified by a load pattern which rises slightly in the early morning then declines steadily through the middle of the day. It again rises in the late afternoon to its maximum in early evening. The load is characterized by lighting, smaller appliances, and cycling appliances, i.e., water heating, refrigeration. This load will also experience its maximum demands during the Winter Season. The second service class is General Service which is characterized by a load which rises slowly and continually from mid-morning and peaks by mid-afternoon. Afterwards it declines through the evening. This load follows the commercial and/or industrial business day. The General Service class will experience its maximum demands during the Summer Season. The third class of service is Transmission-Water Authority. This load is specific to the Company's territory in that it serves the Massachusetts Water Resource Authority (MWRA) on Deer Island. This load is distinct from General Service since its shape is independent of both season and time-of-day. This is a high voltage continuous service class. The fourth basic category is Transmission-Traction load. This load is also specific to the Company's territory, in that it serves the Massachusetts Bay Transportation Authority. This load is distinct from its General Service since it rises during the morning rush hour, falls during the business day, rises during the evening rush hour and falls off again in the late evening. Consequently, it was selected as an individual service class. The characteristic of this Transmission-Traction load is high voltage continuous service. This class shows no pronounced seasonal variation. Lastly, the Lighting class is distinct in that it is wholly deterministic. The service is dependent only on hours of darkness. Lighting may be on-peak or off-peak depending on the season, but its pattern is not price sensitive.

As a result of the Company's load analyses, these five basic classes of service were identified. Further, these classes defined the discrete embedded cost allocations. The Company does not believe it is prudent to abandon all sensitivity to embedded cost information which would result from an allocation to service classes based on marginal revenue, such as an equi-proportional approach of marginal cost reconciliation. Conversely, it is not appropriate to constrain marginal prices which should predominate, to the allocated embedded costs of each rate schedule. The solution is therefore to broaden greatly the class definition, but not abandon the embedded cost process completely.

Q11. **Has the determination of the service class allocation basis followed from prior Department directives?**

A. Yes, the use of a service class basis provides a greater stability to ultimate rates and improves intraclass equity. The Company was ordered to address the issue of intraclass equity _vis a vis_ eliminating intraclass revenue shifts (DPU 85-271A, p. 231). The focus of the investigation was the consequences of its rate class heterogeneity. The Company believes that the difficulties with rate class heterogeneity can be lessened, especially as they create obstacles to equity and stability. Clearly heterogeneity can be minimized by reducing the number of customers in a rate class to those falling within very narrow load/usage bands. This would, of course, lead to an unmanageable proliferation of rate schedules. Conversely, intraclass continuity can be improved by allocating to broad, distinct usage types and building individual rates schedules from marginal cost. Similarly, there are and will continue to be significant migrations between rate schedule in the absence of a broad service class definition. These migrations necessitate continually rebalancing revenue requirements as well as continually risking substantial revenue shifts. These problems are addressed and largely eliminated by the development of broad service classes.

Q12. Based on the service classes would you please explain the Company's allocation methods and the rationale used in developing embedded revenue requirements.

A. The major allocation factors used at each functional level are:

1) Production - demand: The Company has developed an ability to allocate production capacity on a unit-by-unit basis. This type of approach known generically as a probability of dispatch (POD) method, was specified in both DPU 1720 and DPU 85-271A as the method by which the Company should allocate production capacity costs in its next rate case.

2) Production - energy: The Company has allocated these costs on the cost weighted kWh usage by period for each class. The energy costs by period are calculated by a dispatch simulation. This approach was used and accepted in the Company's prior rate cases DPU 85-271A, DPU 1720 and DPU 1350.

3) Transmission - demand and distribution-demand: The Company, in compliance with DPU 1720, investigated the feasibility of time differentiating the allocation of demand related transmission and distribution (T&D) costs: The Department expressed a preference for such a method, if it could be developed. The Company reported its findings to the Department in January 1985, stating that a method

analogous in principle to the POD at the production level was likely to improve the accuracy of the T&D allocation and could be developed by the next rate case. The probability of demand for T&D cost was subsequently used and approved by the Department in DPU 85-271A. The T&D method used by the Company separately allocates delivery costs by voltage level throughout the load duration curve based on a probability of peak coincidence.

4) <u>Distribution - customer</u>: The Company allocated joint customer costs based on the number of customers or weighted number of customers. Where costs were specifically associated with only one class, they were directly assigned. Customer costs were allocated in the same manner as was accepted in DPU 85-271A and DPU 1720.

Q13. Would you please further explain the production POD method?

A. A POD allocation determines the capacity costs associated with each hour by allocating the capacity costs of each generating unit to each hour in proportion to the probability of the unit being run during the hour.

The POD was computed by a set of programs called FAD.URSA. The dispatch was simulated on a fully allocated or normalized maintenance basis. As input, the dispatch requires an operating specification of each unit including running costs, minimum and maximum loading, equivalent forced outage rates, maintenance time, etc. The units are then dispatched against the hourly loads in the test year; in this case the period was January 1, 1991 - December 31, 1991. The units are required to fill the envelope of the load duration curve with the least cost mix of generating units at each load level given maximum loading constraints and availability.

This probabilistic approach recognizes that units may and do fail. This failure, however, is predictable in terms of total time out of service, but random in terms of when and to what extent a unit may be out of service. The probability of failure of any unit creates an equal probability of an increasing energy requirement from units higher in the dispatch. Thus, each unit is dispatched against a probability-weighted load duration curve. The equivalent load duration curve is calculated by the weighted probability of failure of units successively lower in the dispatch. A unit is thus dispatched at its "most probable" output for each load level.

Once all units were allocated across all hours on the basis of probability of use, the cost in each hour was allocated to each rate class in proportion to its share of total demand in each hour. The class' load, as a ratio of system load used in this allocation process, was derived from the Company's load research program. The Company used its own-load dispatch to determine its capacity costs by period and thus its associated capacity revenue requirements by period because these costs are determined by the Company's own production inventory and how that inventory can meet its load.

Similarly, both marginal and average period running costs were determined by the dispatch of the Company's production resources against its own load. The use of a company's available firm production sources dispatched against its own firm load is referred to as own-load dispatch.

Q14. Is the Boston Edison own-load dispatch the appropriate source for computing average and marginal energy costs?

A. Yes, the own-load dispatch is the appropriate basis for computing costs. The New England Power Pool Capacity cost responsibility is based upon the Boston Edison Company's ability to serve its own load with its own resources. For example, if the Pool has a nuclear unit at the margin and the Company has an oil unit at its margin, the Company's cost is based upon the running cost of the oil unit. Since the Pool would, in fact, dispatch and run the lower cost unit and make an intra-pool transaction, the Company would receive a small savings share from the Pool. This would lower the Company's average and marginal cost very little, certainly not down to the running cost of a nuclear unit.

Furthermore, as the Department has ruled, the costs used in the ratemaking process should be normalized to reflect typical operating procedures. Unusual or prolonged outages, or even certain planned maintenance, such as refueling, are normalized for ratemaking purposes.

Q15. Has Boston Edison Company previously used the POD methodology for determining the allocation of production costs among classes of service?

A. Yes. In the prior retail filings, DPU 85-271A and DPU 89-100, the Company used this methodology. However, the Company was directed to investigate the feasibility of simplified alternatives which capture the essence of POD allocation for its next rate filing and these findings are discussed in my testimony in DPU 89-100.

Q16. Please summarize those findings.

A. In summary, the analysis showed that the probability of dispatch method (POD) can be approximated by simpler, static allocation methods. A comparison of alternative methods including a variety of demand and energy allocations were evaluated and presented showing the diverse results. The finding was that the POD was not fully reproducible and that it could not be replicated. Finally, the conclusion was that the POD should remain as the basis for revenue requirements and rates.

Q17. Mr. La Capra, please explain your reference to an adjustment to the power supply allocation basis for the MBTA 115kV service.

A. The POD allocation of power supply was adjusted for the MBTA service at 115kV. Specifically, the MBTA is supplied under a special contract which provides for a power supply assignment based on its annual energy use and the average of its contribution to the four summer monthly peaks. This allocation basis can be described by the expression:

$$\text{MBTA\%} = \left[\frac{(\text{MWh}_m)}{\text{MWh}_s}\,\text{Lf} + \frac{(\text{4CP}_m)}{\text{4CP}_s}\,(1-\text{Lf}) \right] \times 100\%$$

Where: MWh_m = Annual Energy at generation of the MBTA

MWh_s = Annual Total Territory Energy

Lf = Territory Load Factor (expressed as a decimal)

4CP_m = The average MBTA contribution to the monthly territory peaks in June, July, August and September, and

4CP_s = The average monthly territory peak for June, July, August and September.

The expression when used for a full territory allocation is referred to as "peak and average" (P&A).

Q18. How was the peak and average and POD method combined?

A. The MBTA 115kV service by prior agreement is assigned its power supply allocation by the above noted formula. The balance of costs are then allocated by the POD method. Mechanically, the adjustment is made by fixing the allocation of power supply to the MBTA, and allocating the balance of power supply costs by a POD method to the other four service classes. If the P&A yields a higher allocation to the MBTA service than does POD in a given year, there is a lessening of power supply cost responsibility to other service classes. If the P&A yields a lower allocation, as in this test year, there is an increase in power supply cost responsibility to other service classes.

Q19. Would you please explain the weighted MWh allocation of energy costs?

A. Energy related costs were allocated on weighted MWh at the generation level. This allocation factor was developed directly from the POD running cost summaries by period. The average running costs for each of the 36 territory load profiles, i.e., typical work day, weekend day and peak day by class and by month or 864 hourly periods were determined by the probability of dispatch simulation. This method also was used in DPU 89-100, 85-271A, 1720 and 1350, although in DPU 1720 and 1350 only four periods were used. The calculation of the energy allocation factor is made by multiplying each service class' MWh in a specific period by the average running cost in that period. By summing these values for each service class and dividing by the average annual running cost, a weighted MWh usage by class was obtained. This weighting of the relative usage of a large number of periods provides for greater accuracy since average (and marginal) fuel costs are different in each period. At the level of 864 periods, differences between successive periods do become very small.

Q20. Would you please explain the allocation of transmission and distribution costs?

A. Transmission and distribution costs were first allocated to time periods and then to service classes. The allocation to time periods followed a probabilistic approach similar in concept to the "POD" allocation of production costs. The T&D costs are allocated to time periods based on the probable load levels and the capacity required at each level. The transmission and distribution probability of demand is based on the probability of coincidence to peak. The less likely that a kW measured at a lower voltage level appears as a kW on peak, the less the coincidence or the higher the diversity. Thus, a lower coincidence indicates a lesser time dependence. As coincidence becomes very low, or diversity very high, it follows that high demands are occurring throughout all periods and distribution costs are less dependent on time and less related to system peak load. For example, in the extreme, a coincidence approaching zero would yield a functional relationship showing no time dependency of costs, i.e., all time periods are equally cost responsible. The allocation of T&D costs proceeds from proceeds from functionalizing transmission (115kV), high tension (13.8kV) and secondary costs, then allocating each functional cost across its specific convolved voltage level load duration curve to arrive at the amount of cost appropriate to each period. The allocation of costs to classes is done for T&D as it was for production, i.e., the relative class usage in each period determines its pro rata share of the period cost.

Q21. How were customer costs allocated?

A. Plant items classified as customer costs included only meters, a portion of services, street lighting plant, and a portion of labor related general plant. The customer plant and associated expense were allocated directly to the service class based on the number of customers, or the customer weighting of a particular installation, e.g., weighted customer meters.

Q22. **Would you please summarize the results of the allocated cost of service?**

A. The results of the allocated cost of service are as follows:

Service Class	Base Revenue Requirement ($000)	Normalized Test Year Base Revenues ($000)	Transfer of Fuel Recovery to Base Rates ($000)	Transfer of PAC to Base Rates ($000)	Deficiency ($000)
Residential	$311,910	$239,752	$14,472	$18,199	$39,487
General Service	593,197	461,597	37,832	47,581	46,187
115kV (MBTA)	6,074	5,012	641	806	-385
115kV (MWRA)	794	997	86	108	-397
Street Lighting	22,141	18,952	640	806	1,743
Total Retail Service	$934,116	$726,310	$53,671	$67,500	$86,635

Q23. **Would you please describe the procedure used to account for losses in the cost of service study?**

A. Metered load data from the Company's load research program were adjusted to the generation level using loss factors for the secondary, primary, high tension and transmission levels. The methodology to develop these factors used FERC Form #1 losses, billing statistics, engineering studies, hourly territory load data and hourly load research data.

Q24. Mr. La Capra, are the allocation methods you used in Exhibit BE-RLC-2 the same as those ordered or approved by the Department in the Company's last fully adjudicated case, DPU 85-271A?

A. Yes, the use of the Company's external and internal allocation methods bases are continued from that rate case with one exception.

Q25. Would you please describe that exception.

A. In previous rate filings, the Company allocated Administrative and General (A&G) Expenses on the basis of total labor. However, the Department's recent decisions in DPU 90-331, DPU 90-300 and DPU 90-106, made it evident that the preferred allocation was on class revenue requirement. Therefore, we have allocated accounts #920, #921, #922, #923, #928, #930, #935 primarily on that basis .

Q26. Have you prepared any exhibits to demonstrate the allocation of costs to each classification of service?

A. Yes, I have prepared Exhibit BE-RLC-2, entitled "Allocated Retail Cost of Service Study", for the 12 Months Ended December 31, 1991, which shows the allocation to the service classes.

Exhibit BE-RLC-2 shows the present revenue, allocated expenses, deficiencies, and proposed revenue for the total electric department and each service class, and consists of 19 schedules, organized into three major categories, i.e., Summary Schedules, Detail Schedules and Factor Schedules. Schedules 1 through 4 are summary schedules showing the total cost of service and revenue deficiency at an 10.82% rate of return, along with summary schedules of rate base, operation and maintenance expense, and adjustments to operation and maintenance expense. Schedules 5 through 16 show each individual rate base and expense item in detail. Schedules 17 through 19 show the development of the various internal and external allocation factors whereby costs were apportioned to service classes.

Q27. Would you please describe each of the schedules in Exhibit BE-RLC-2 in more detail?

A. Schedule 1 summarizes the cost of service and revenue deficiency at a rate of return of 10.82%. The Company's retail rate revenue requirement of $1,305,107,000 is separated into fuel revenues of $370,991,000 and a base rate revenue requirement of $934,116,000. The base rate revenues of $726,310,000 after the adjustment for the transfer of fuel Recovery base rates of $53,671,000 and the transfer of PAC to base rates of $67,500,000 leaves a base revenue deficiency of $86,635,000.

Schedule 2 is the summary of net electric operating income and rate base. This schedule shows the normalized operating revenues, operating expenses, net electric operating income, and electric rate base. This schedule also indicates the actual return at existing rates of return and the return including the proposed increase. The apportionment of the proposed increase to each class completes the equalization of rates of return among classes in keeping with the objectives begun in DPU 1350 and continued through DPU 89-100. The allocation of the revenue increase is more fully described in the testimony of Mr. R. D. Saunders, Exhibit BE-RDS-1.

Schedule 3 summarizes the allocation of operation and maintenance expense by the major functional categories to each classification of service. This summary schedule also shows the total operation and maintenance adjustments.

Schedule 4 shows the detail of all operation and maintenance adjustments, the method by which they are allocated to individual classifications of service and a summary of the inflation allowance.

Schedule 5 shows the allocation of depreciation, amortization and taxes other than income taxes to the various classifications of service.

Schedule 6 shows the computation of federal income and Massachusetts corporate franchise taxes among the various classifications of service. This schedule is based on the claimed return of 10.82% and shows the income tax adjustments, tax credits and taxable income for the test year. Page 2 of Schedule 6 shows the development of taxable income, federal income tax and Massachusetts franchise tax at the current operating revenues.

Schedule 7 is the summary of electric plant in service by major functional category as well as the total adjustments to electric plant.

Schedule 8 shows accumulated depreciation by major functional category.

Schedule 9 details the additions and deductions from net plant and their allocation to the various classes. The net plant additions include nuclear fuel, the Pilgrim transmission line, materials and supplies and cash working capital. The deductions are comprised of accumulated deferred income taxes, unamortized investment tax credits, unclaimed funds and customer advances for construction.

Schedule 10 shows the total operating revenues, base, PAC and fuel electric operating revenues and other operating revenues, including other sales of electricity, non-residential interest charges, miscellaneous service revenues, rents from electric properties and other electric revenues. Sales of electricity are assigned directly to classes of service while other operating revenues are allocated based on the nature of their occurrence.

Schedule 11 shows the detail of the allocation of operation and maintenance expense by three-digit account. Supervision and engineering expenses are allocated on labor accounts, fuel expenses on weighted kWh at the generator and operation and maintenance expenses on the basis of comparable plant in service and customer records. Administrative and general expenses are considered either plant, labor, energy or revenue related and appropriately allocated by plant in service, labor, energy or revenue allocation factors.

Schedule 12 shows the detail of the inflation allowance. This schedule explains the allocation of the escalation portion of non-fuel and non-labor portions of O&M expense shown in Schedule 11. Each expense escalation is allocated to classes on the basis of the corresponding O&M account.

Schedule 13 shows the detail of the allocation of electric plant in service by three-digit account and major functional category. Production, transmission and distribution plant are functionalized and allocated on corresponding external factors. General plant is allocated on labor with the exception of Account 399 which is allocated on total plant. Schedule 13 also includes the allocation of the adjustments to electric plant.

Schedule 14 shows the allocation detail of the working capital computation. Working capital consists of materials and supplies, fuel inventory, thirty days of fuel and purchased power expense and forty-five days of net operation and maintenance expense.

Schedule 15 shows the detail of allocation of accumulated deferred income tax.

Schedule 16 shows the reconciliation of fuel revenue and fuel expense. Fuel revenues include retail and Wholesale S-rate amounts, contracts, and recovery of transmission expenses collected via the fuel charge.

Fuel and purchased power expense is made up of Accounts 501 (Part), 518, 547, 555 (Part), 565 (Part), and the C&LM part of Account 908.

Schedule 17 shows the derivation of all external allocation factors used in the prior schedules. The external allocation factors are summarized by major classification, i.e., the energy allocation factors, the demand allocation factors, the direct assignments and customer related factor, and the various constants used in allocation.

Schedule 18 details each of the internal factors. Internal factors are those which are created from lines, accounts or groups of accounts previously allocated by external factors. They are internally generated and derived from prior calculations.

Schedule 19 shows the detail of the labor allocation. This schedule shows the labor component of each three digit operation and maintenance account and how it was allocated to the various classes of service by external or previously developed internal allocation factors.

Q28. Would you please identify the function, classification and allocation of each cost of service account?

A. Yes, Exhibit BE-RLC-3 identifies each cost of service account and specifies its function, classification and allocation. The first table, Table A, of this exhibit parallels the cost of service format specifying each account by name and account number in the left column. The center column of Table A indicates whether the account has been, 1) transferred from another schedule, 2) created by an arithmetic combination of other accounts, 3) allocated by a specific factor, another account or group of accounts, or 4) directly assigned. The last column in Table A shows the schedule and line source within the cost of service study for each transfer, calculation, allocation or assignment. Table B of Exhibit BE-RLC-3 references each allocation factor by its function, and classification as well as a schedule and line reference to its use within the cost of service.

Q29. Turning to the third area of your testimony Mr. La Capra, please explain the steps the Company has taken in its load research program since DPU 85-271A.

A. As a result of the order in DPU 1720, Boston Edison Company accelerated its load research program to monitor continuously all rate classes. Currently, the Company has fifteen load research surveys in place which represent approximately 3,000 load research meters on its retail rate classes.

Exhibit BE-RLC-4, entitled "Summary of Surveys in 1991", contains a tabulation of the rate classes being surveyed during the 12 Months Ended December 31, 1991, including the sample design criteria of each survey. The exhibit also shows the contribution of each surveyed rate code, in percent, to annual kWh output and annual peak demand in the test year. Of note is the fact that the Company has load research meters on rate classes that represent in excess of 98% of annual kilowatthours and 99% of annual peak demand.

Q30. How does the Company perform sample design?

A. For surveys other than 100% sampled, the Company uses stratified random sampling techniques for the survey design which divides a population into homogeneous, non-overlapping subgroups or strata. Together, the strata form the entire population.

In some instances, the sample also includes one stratum of 100% sampled customers. This practice reduces the required overall sample size while maintaining the desired sample accuracy. The size of the stratified sample is determined by the Neyman allocation which minimizes the variance of the sample mean for a fixed sample size. The construction of the strata boundaries is accomplished using the Dalenius Hodges rule which selects stratum divisions so that equal cumulative scales result.

The total sample size is determined by selecting a random sample within each stratum that meets the target accuracy level. The specified sample size for each strata is increased by twenty percent to allow for data collection problems.

Q31. Would you please describe the metering and translating processes of the load research program?

A. The Company collects fifteen minute interval data from over 3,000 load research meters. Traditionally, the Company utilized magnetic tape recorders to collect this type of data but the trend is now towards state-of-the-art electronic meters/recorders. There are approximately 600 magnetic tape recorders and 2,400 electronic recorders on the Boston Edison system as of December 1991.

To process the data from these recorders, the Company purchased a comprehensive computer package of load research software called LODESTAR. The LODESTAR system consists of both a load data management subsystem and load analysis subsystem.

The load data management programs read in the interval data from load research meters and store it in a historical data base by customer location. The Company's load research data base goes back to 1978 when the first magnetic tape recorders were installed. Within the data management subsystem, the LODESTAR programs allow the data to be edited, plotted, reported and eventually archived.

The LODESTAR programs in the load analysis subsystem extract the records from historical data base for analysis usually by rate schedule, rate code or service class. Within the load analysis subsystem, the data can also be reported, plotted, aggregated and transformed for ad hoc analysis. All reported statistics are stored in a historical analysis data base.

Q32. **What is the target accuracy of load research surveys?**

A. The target accuracy of the Company's load research surveys is typically at the 95% confidence level with ± 5% accuracy for large rate classes while 95% confidence with ± 10% for smaller classes is the rule.

The following is a summary of the Company survey designs in comparison to territory load for the test year based upon Exhibit BE-RLC-4 entitled "Summary of Surveys in 1991":

Design Accuracy	Percent of Annual Output	Percent of Peak
100% Sampled	48.68%	45.50%
95% @ ± 5%	49.93	54.20
95% @ ± 10%	0.21	0.24
Totals	98.82%	99.94%

The remaining rates for which load research meters are not in place include only streetlighting.

The kilowatthour usage of streetlighting represents 1.2% of the Company's annual sales and contributes only a small amount to the territory peak. To estimate streetlighting usage, we have developed an annual load shape equivalent to 4,200 burning hours based on sunrise and sunset tables.

Q33. **Please explain the development of the test year load data.**

A. To develop load data for the probability of dispatch program, the Company used actual 1991 load research data from the sample surveys described in Exhibit BE-RLC-5.

For purposes of flexibility in the cost-of-service study, it was required that forty-eight load shapes be developed for each hour of the test year. These load shapes by rate code were then aggregated into sixteen probability of dispatch (POD) groupings. Then on a monthly basis, three day types were produced for the POD program which included average weekday, average weekend and territory peak day. This translates into 576 POD load shapes for the test year. Exhibit BE-RLC-5 provides a list of the aggregated POD load shapes and the load research survey data applied to each rate code. The final load shapes were prorated to match billing kilowatthours and then brought up to the generation level using hourly loss factors.

As a test of the reasonableness of this approach, comparisons between recorded territory load and a summation of the ~~fourteen~~ aggregated POD load shapes were made. For the territory peak day, all months of aggregated load shapes are within ± 5% of actual peak. Similarly, the percentages of annual on-peak and off-peak usage were within less than 1% of actual territory output.

Boston Edison Company
DPU 92-92
Exhibit BE-RLC-4

LOAD RESEARCH PROGRAM

SUMMARY OF SURVEYS IN 1991

BOSTON EDISON COMPANY

Load Research Program

Summary of Surveys in 1991

Survey Number	Rate Designation	Rate Codes	Recorder Type	Design Criteria	Sample Size	Annual Output	Annual Peak
27	G-1	011, 018, 078, 191, 193	TMR	95% ± 5%	145	3.39%	4.92%
28	G-2	019, 112, 113, 130, 214, 234, 314, 430	TMR	95% ± 5%	150	18.69%	19.92%
29	G-2	079, 274, 374	TMR	95% ± 5%	78	1.32%	2.06%
2	G-3	417,477	MT	100% Sampled	452	21.29%	18.00%
N/A	G-3	507	MT	100% Sampled	1	0.96%	0.66%
4	G-3	407	MT	100% Sampled	4	0.14%	0.10%
30	R-1	020	TMR	95% ± 5%	228	19.84%	22.37%
21	R-1	021	TMR	95% ± 5%	151	2.38%	2.47%
23	R-1	022, 023	TMR	95% ± 5%	234	4.31%	2.46%
22	R-2	030, 031, 032, 033	TMR	95% ± 10%	58	0.20%	0.23%
26	R-4	224, 225, 226	TMR	95% ± 10%	29	0.01%	0.01%
6A-M	T-2	607, 617, 627, 677, 707, 717, 777, 907, 917, 977	MT/TMR MT/TMR MT/TMR	100% Sampled 100% Sampled 100% Sampled	1446	22.50%	23.11%
N/A	MT	506	MT	100% Sampled	1	1.19%	1.05%
N/A	WR	510	MT	100% Sampled	1	0.14%	0.00%
N/A	S-9	Concord & Wellesley	MT	100% Sampled	8	2.46%	2.58%
N/A	NE	512	MT	100% Sampled	1	N/A	N/A
	TOTAL				2987	98.82%	99.94%

Key: MT Magnetic Tape recording device
TMR Electronic recording device (either Model 82 or Model 92)

Q34. Please describe Exhibit BE-RLC-6.

A. Exhibit BE-RLC-6 displays the cost of service for both State and Federal jurisdictional amounts as required by DPU 1720. The Exhibit provides cross referencing between the overall cost of service Exhibit BE-MSA-4 and the allocated cost of service Exhibit BE-RLC-2.

Q35. Does this complete your testimony?

A. Yes, it does.